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Enhancing CO_2 Solubility in the Aquifer with the Use of a Downhole Cooler Tools

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Abstract

Different injection methods have been already proposed by different researchers to improve the solubility of CO_2 in the formation brine. In this study a novel injection technique is presented, its aim being to cool down (liquefy) the supercritical CO_2 injected in the wellbore by the use of a downhole cooler equipment. The higher temperature CO_2 enters the cooling equipment and exits with a lower temperature further downstream. If the temperature of the downhole, where CO_2 contacts the formation brine, decreases to the lowest possible safe operational temperature, the consequence is an increase in the solubility of CO_2 to the highest possible value for that pressure. The colder (liquid) CO_2 has a higher solubility in brine, higher density and viscosity, which increases the security of the CO_2 storage. With this method the supercritical CO_2 is cooled down to a liquid phase to increase the solubility at the wellbore thereby eliminating the risk of phase change or pressure and rate fluctuation in the liquid CO_2 injection from the surface. Additionally the formation will have a lower pressure build-up because CO_2 and brine are well mixed, and so less CO_2 remains in the free phase.

Key Words: CO2 storage, Cold CO2 injection, CO2 solubility, Storage security

1. Introduction

The concentration of CO_2 in the atmosphere has increased up to 45% the since the industrial revolution (Bachu et al. 2015). Carbon capture and storage (CCS), that comprises the separation of

CO_2 from the gaseous exhaust of power plants and other heavy industries and its subsequent safe and secure long-term storage in geological formations is considered as the most applicable method for mitigation of CO_2 concentration in the atmosphere (Metz, Davidson et al. 2005, Bachu 2008, Jiang 2011). The best storage sites are those that trap the CO_2 as an immobile phase under the ultra-low permeability confining reservoir caprock where it is subjected to further gradual physical and chemical trapping mechanisms (Metz et al. 2005). In the long-term, several trapping mechanisms are active in the aquifer which are categorised as: structural trapping, residual trapping, solubility trapping and mineral trapping (Garcia, Kaminska et al. 2010). Since the leakage from the storage sites can create harmful environmental defects, the security of long-term storage is of a great importance (Metz et al. 2005, Gasda, Bachu et al. 2004, Nordbotten, Celia et al. 2005, Burton, Bryant 2007a, M. A. Celia, Nordbotten et al. 2011). In this regard, researchers have proposed different engineering techniques in order to improve the solubility of CO_2 in the formation brine. When the CO_2 is dissolved in brine the density of the formation brine increases by 1%, resulting in the dissolved CO_2 sinking in the reservoir and preventing any upward migration of the free CO_2 phase towards the caprock (J. Ennis-King, Preston et al. 2005, Riaz, Hesse et al. 2006). (Emami-Meybodi, Hassanzadeh et al. 2015) have categorized these engineering techniques into subsurface dissolution, surface mixing and downhole mixing.

Cold CO_2 injection in the liquid phase from the surface is a method which has been proposed to be energetically efficient injection (Silva, Carrera et al. 2011). In the liquid phase the density of CO_2 is close to that of water, thus it sinks downwards and requires less compression energy. The thermal stress imposed by the temperature difference resulting from cold CO_2 injection, however, might cause some damage, such as the wellbore cement failure resulting in the creation of some fractures in the cement and forming pathways for the CO_2 to leak away (Teodoriu 2013, Kaldal, Jónsson et al. 2015, Roy, Morris et al. 2018). Additionally, the temperature decrease under the hydrate formation zone for CO_2 may result in creation of hydrate which blocks the pores and decreases the injectivity (Uchida 1998, Zhang, Yang et al. 2017). Moreover, cooling the reservoir around the injection well will create a thermal stress that might induce fracture instability which should be avoided in the caprock because they might create leakage pathways (Vilarrasa, Olivella et al. 2014, Salimzadeh,

Paluszny et al. 2018, Vilarrasa, Makhnenko 2017, Luo, Bryant 2011). (Vilarrasa, Silva et al. 2013) investigated liquid CO_2 injection from the surface and they analysed the evolution and the thermo-hydro-mechanical response of the formation and caprock. They proposed that injecting CO_2 in the liquid phase is more efficient because liquid CO_2 is denser resulting in less over pressure due to less water being displaced and requiring less compression energy. Other injection techniques have been proposed by different researchers which are briefly as follows: (Xue 2009) proposed microbubble sequestration in which the atomized foams of CO_2 in gas, in supercritical or liquid phase, are dispersed into the pores of variety of rocks. The CO_2 microbubbles with a size of less than 10 micro-metres will shrink and quickly dissolve into the brine. They propose that microbubbles of CO_2 do not tend to create a uniform large bubble, which has a large buoyant force in the ground water. (Ozah, Lakshminarasimhan et al. 2005) presented an injection strategy to use horizontal wells low in the formation, referred to as “Inject Low and Let Rise”. In this regard, all or a huge part of the CO_2 will trap, dissolve or be precipitated before reaches the seal of the formation. (Leonenko, Keith 2008) suggested to lift the brine from the areas of the aquifer not already saturated with CO_2 and then inject it to the areas occupied by CO_2. (Hassanzadeh, Pooladi-Darvish et al. 2009) addressed a new method for accelerating CO_2 dissolution in aquifers by injecting brine on top of the injected CO_2. In another approach, (Shariatipour, Mackay et al. 2016) proposed an engineering solution in which brine extracted from the top of the aquifer is mixed by a downhole mixing tool with CO_2 which is injected through the tubing. Then, the dissolved CO_2 in brine is injected into the same formation through another lateral at the bottom of the aquifer. In this new study, an engineering injection technique is presented to increase the solubility of CO_2 in brine by implementation of downhole cooling equipment to cool down the injected CO_2 in the bottom of the well thereby eliminating the risk of phase change or pressure and rate fluctuation in the liquid CO_2 injection from the surface.

2. Methodology

The main focus of this work is to present a method to maximize CO_2 solubility in brine in downhole conditions where the injected CO_2 first comes into contact with the formation brine. The idea comes from the well-known rule that the solubility of CO_2 in brine increases with a decrease in temperature (Spycher, Pruess et al. 2003, Duan, Sun 2003). Thus, our proposed idea is to install tools that can

effect a decrease in the temperature of the injected CO_2 in the wellbore where the CO_2 contacts with brine (Fig. 1). The advantage of this method is that when the temperature decreases, the highest possible amount of CO_2 corresponding that pressure could be dissolved in the formation brine (theoretically) and Not only does this proposed methodology minimize the amount of free CO_2 entering the formation, but also since the CO_2 saturated brine has a higher density than the fresh formation brine it will sink to the bottom of the formation. The consequence is that less CO_2 migrates upward towards the top seal thus increasing the storage security. Additionally, the denser brine creates a convective flow regime, thereby accelerating the dissolution of CO_2 in brine within the reservoir (J. P. Ennis-King, Paterson 2005, Kneafsey, Pruess 2010).

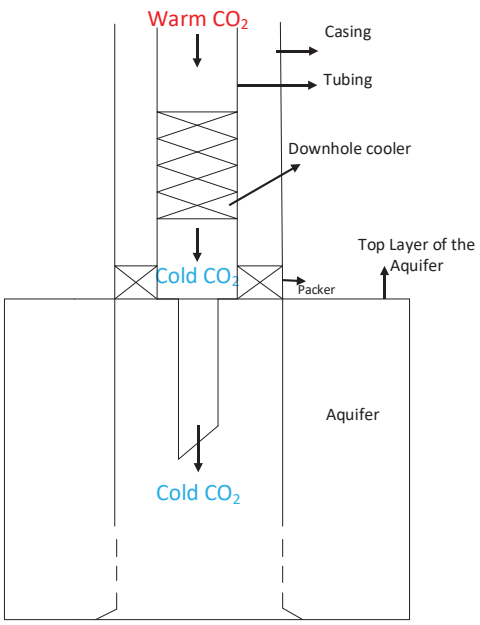

Fig. 1: Schematic of the downhole cooler equipment and process.

Moreover, another effect of cold CO_2 injection is the creation of thermal stress which results in fracturing near the wellbore formation (Oldenburg 2007) and an increase in injectivity. These fractures may also act as a path way for CO_2 upwards which may increase the risk of leakage (Bissell, Vasco et al. 2011a, Nimtz, Klatt et al. 2010). Generally, it is more desirable that the CO_2 is injected in a supercritical condition to prevent problems created by phase change in the pipeline and the length of the tubing in deep formations (Nimtz et al. 2010). Although liquid injection of CO_2 has been proposed as a method to not convert CO_2 into supercritical phase at the surface, non-isothermal

studies show that the temperature of CO_2 must be decreased considerably (down to -10 ˚C) at the surface in order to remain in the liquid phase in the tubing considering the heat exchange with surrounding until a depth of 1500 m causing the problem of phase change (i.e. pressure and rate fluctuation) within the wellbore (Vilarrasa et al. 2013). Using this new technique, however, means that we can ensure that the CO_2 is converted to liquid (in case of a high temperature decrease) only in the wellbore while it is in the supercritical phase in the tubing preventing any phase change problems there. Additionally, by implementing this equipment we can maintain a precise control of the temperature of the CO_2 in the downhole in terms of rock mechanics stability and CO_2 dissolution in brine. Surface mixing of CO_2 with brine, which has been already presented as an efficient way of CO_2 injection, is very expensive, while CO_2-enriched brine result in high levels of corrosion on surface equipment due to its acid nature (Burton, Bryant 2007b). Usually the normal temperature to ensure that the CO_2 is in the supercritical phase in the downhole of a well is approximately 40 ˚C at the surface (Nimtz et al. 2010, Vilarrasa et al. 2013, Möller, Liebscher et al. 2014). Analytical calculations show that assuming a temperature of 55 ˚C and a pressure of 150 bar (i.e. the top layer of Bunter Sandstone in the UK Southern North Sea), a 30 ˚C decrease in temperature results in near 20% increase in CO_2 solubility in brine at the same pressure (Spycher et al. 2003, Spycher, Pruess 2005). The temperature decrease in a section of the wellbore can be created by implementing tools that use the external energy of a colder fluid. We can install a throttling valve in the wellbore to decrease the pressure, with the consequence that the temperature decreases based on the Joule-Thomson effect in an isenthalpic process to cool down the injected CO_2 (Oldenburg 2007, Mathias, Gluyas et al. 2010). It should be noted that the temperature decrease must not be under the hydrate formation region (approximately 12 ˚C), which may cause the formation of hydrate (Zhang et al. 2017) and blocking the pores and decreasing the injectivity (Fig. 2). Additional pressure, however, might be applied at the wellhead to compensate for the pressure drop in the throttling valve which may cause some additional operational expense. This downhole cooler equipment can also be utilised along with other methods already presented in the literature to improve their performance.

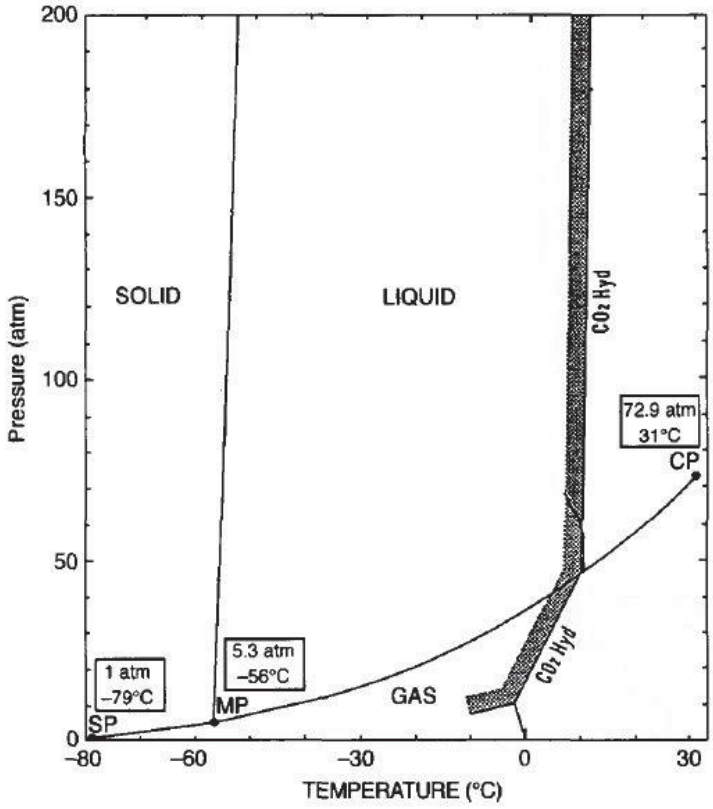

Fig. 2: The CO_2 phase diagram and the Hydrate formation zone for CO_2 (Uchida 1998).

Several models have been proposed to date to investigate the non-isothermal flow of CO_2 through the injection well (Hagoort 2005, Lu, Connell 2008, Han, Stillman et al. 2010) and we have used the equations presented by (Lu, Connell 2008) and solved the equations using the assumption that the kinetic energy term can be neglected (Paterson, Lu et al. 2008).

$$\rho_m \frac{dv_m}{dz} + v_m \frac{d\rho_m}{dz} = 0$$

(1)

$$\frac{dP}{dz} + \rho_m v_m \frac{dv_m}{dz} = -f \frac{\rho_m v_m^2}{4R_w} + \rho_m g \cos\theta$$

(2)

$$\frac{dh}{dz} + v_m \frac{dv_m}{dz} = g\cos\theta - \frac{Q(z)}{\pi R_w^2 \rho_m v_m}$$

(3)

$$dh = \left[V - T\left(\frac{\partial V}{\partial T}\right)_p \right] dp + C_p dT = C_p \mu_{JT} dP + C_p dT$$

(4)

where, ρ_m is the density of the mixture, v_m is the velocity, z is the well depth, f is the friction factor, h is the enthalpy of the mixture and Θ is the well inclination. Q(z) in equation (3) is the heat exchange between flowing fluid and the surrounding of the well which is calculated as $Q(z) = -2\pi R_w U\left[T - T_{wb}(z)\right]$ (Equation (5)). R_w is the well diameter and U is the overall heat transfer coefficient for wellbores. Solving the above equations gives the temperature profile in an injection well and the temperature of the CO_2 in the bottom hole. The non-isothermal calculations show that if CO_2 is injected at a temperature of 45 ˚C from the surface while the surface temperature is 15 ˚C, the CO_2 will reach the bottom hole of the well at a depth of 1500 m at a temperature of 52 ˚C (Fig. 3). The analytical calculations show that if the temperature decreases from 52 ˚C to 20 ˚C, there will be near 20% increase in CO_2 solubility in brine in theory (Duan and Sun, 2003).

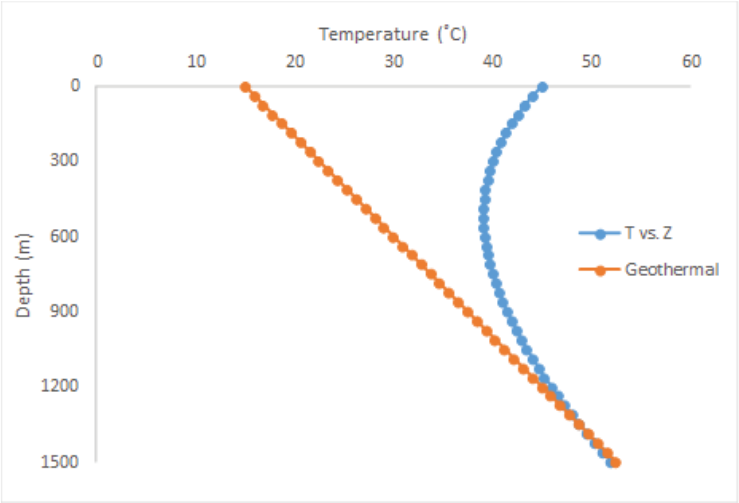

Fig. 3: the Non-isothermal temperature profile through the injection well.

In order to cool down the CO_2 from 52 ˚C to 20 ˚C two methods are considered: 1) installing devices to extract heat from the flowing CO_2 in the well; 2) Installing a throttling valve to drop the pressure instantly and decrease the temperature based on the Joule-Thomson effect.

3. Model Setup

The three-dimensional reservoir simulation model for studying CO_2 injection in a saline aquifer was created by the Eclipse 300 through the CO2STORE option combined with the THERMAL option. The dimensions of the model are 1600m long, 800m wide and 140m thick which is discretised into 80×40×70grid blocks, respectively. The main input data and the thickness of the formation were adopted from the work by Heinemann *et al.* (2012). The porosity and horizontal permeability in the homogeneous case is 0.18 and 250 mD, respectively, and with a K_v/K_h ratio of 0.1 for the base case. For the heterogeneous case, the heterogeneity data were generated based on the same mean as the homogeneous model. Fig. 4 shows the heterogeneous model used in this study. The thermal conductivity of water and rock were calculated based on (Sengers, Watson et al. 1984, Eppelbaum, Kutasov et al. 2014). The model input data is shown in Table 1.

Table 1: The model input data

Input Data	Value
Model size (m)	1600×800×140
Number of grid blocks	80×40×70
Horizontal Permeability (mD)	250
Porosity	0.18
Kv/Kh Ratio	0.1
Depth (m)	1500
Rock Compressibility (1/bars)	5.56e-5
Thermal Conductivity of Water (kJ/m.day.K)	56.5
Thermal Conductivity of Rock (kJ/m.day.K)	158
Injection rate (Mt/year)	1

As there is no way to simulate the cooler equipment separately in the downhole of the well in this regard, it is considered that the CO_2 is injected with a lower temperature (i.e. 20 ˚C) than the reservoir from surface through the use of THERMAL option. The injection rate is determined at a constant value of 1 Mt/year through a vertical well for the base case and the injection pressure should not exceed the fracture pressure of the formation rock. In this regard, the method presented by (Brook, Shaw et al. 2003) was used to calculate the fracture pressure of the formation. We considered the bottom hole pressure constraint as 90% of the fracture pressure of the formation (Williams, Jin et al. 2013). The pore volume of the outer sides of the model are multiplied by 1000 in order to show that the model is a part of a larger aquifer. The injection process progresses for 20 years, then the injection stops and the simulation is continued up until 100 years. It should be noted that this work does not consider the design of such a heat exchanger device but we only consider the idea of utilization of such an equipment.

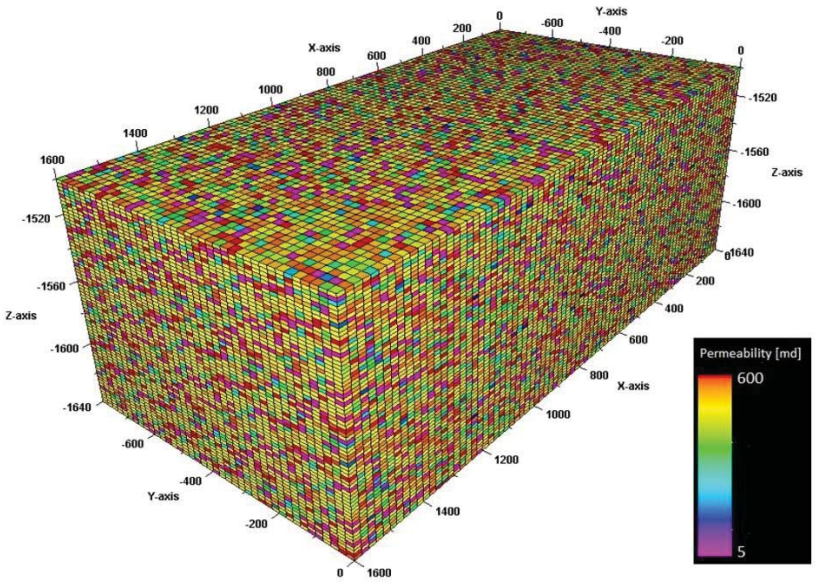

Fig. 4: Heterogeneity of horizontal permeability between 5 md - 600 md.

4. Results and discussion:

4.1 Application of the downhole cooler tools at the depth of 1500 m

Fig. 5 shows the amount of dissolved CO_2 saturation in brine in both homogeneous and heterogeneous models with and without applying the cooling method. As can be seen in the left

side figures, because the CO_2 in the base case is less dense and less viscose it moves upwards and reaches the top of the formation. In the right hand side figures, however, the CO_2 has been injected with a lower temperature in the liquid phase and consequently with higher density and viscosity. Therefore in the same duration it becomes more dissolved in the brine in the lower part of the aquifer and CO_2 plume does not reach the top of the formation and no gravity override has been observed. Additionally, analytical calculations show that by a decrease in temperature from 52 ˚C to 20 ˚C for in the same pressure (150 bar), the viscosity and density of the free CO_2 increases by 71% and 34%, respectively. This creates a reduction in the gravity override and so viscose forces will have more impact on the movement of CO_2 in the aquifer in comparison to buoyant forces (Rayward-Smith, Woods 2011). It should be noted that the low temperature CO_2 cools down the vicinity of the wellbore and as it moves farther into the aquifer the temperature of that will increase due to the geothermal temperature. The cooled area around the wellbore, however, remains for a long time and it takes time longer than the injection time to warm up again (Vilarrasa, Rutqvist 2017).

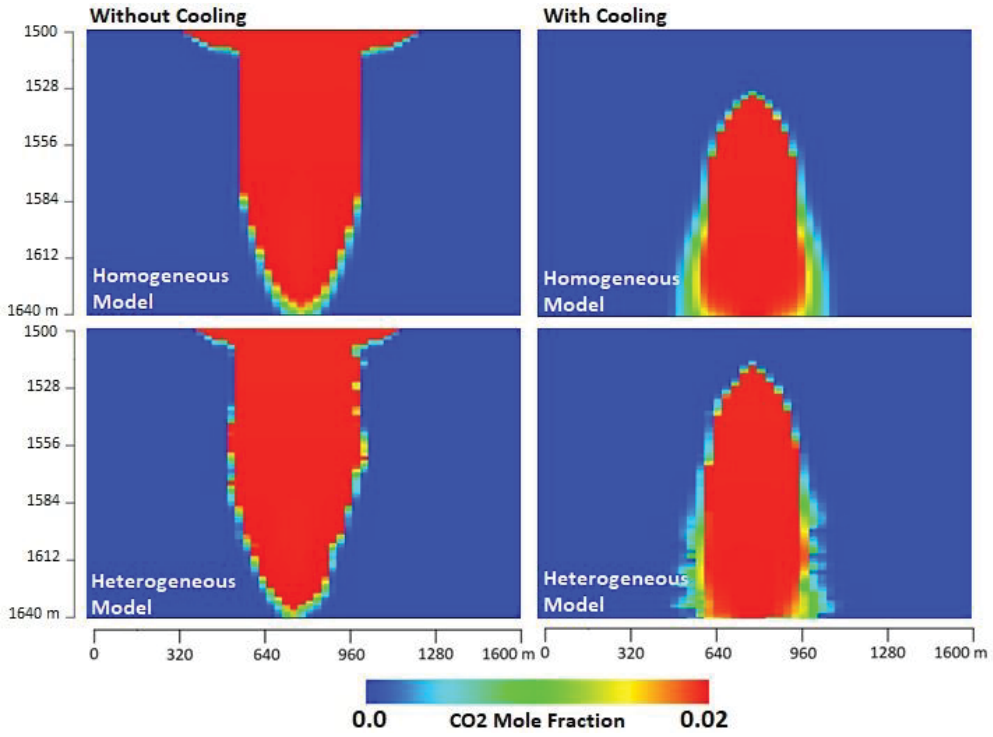

Fig. 5: Dissolved CO_2 in the aquifer brine after 20 years.

Fig. 6 presents the uniform pressure distribution in the aquifer for the two cases. As shown, by the use of the new technique the pressure build up in the formation is less than the base case in which CO_2 is injected with a higher temperature because more CO_2 is dissolved in the formation brine and less stays in the free phase. Furthermore, as the cooled and denser CO_2 occupies a lower capacity of the reservoir rock and less brine will be displaced, thus the pressure increase in the formation will be smaller (Vilarrasa et al. 2013, Randolph, Saar et al. 2013, Zhao, Cheng 2015). It should be noted that in order to see the pressure build up in the model a closed model is considered.

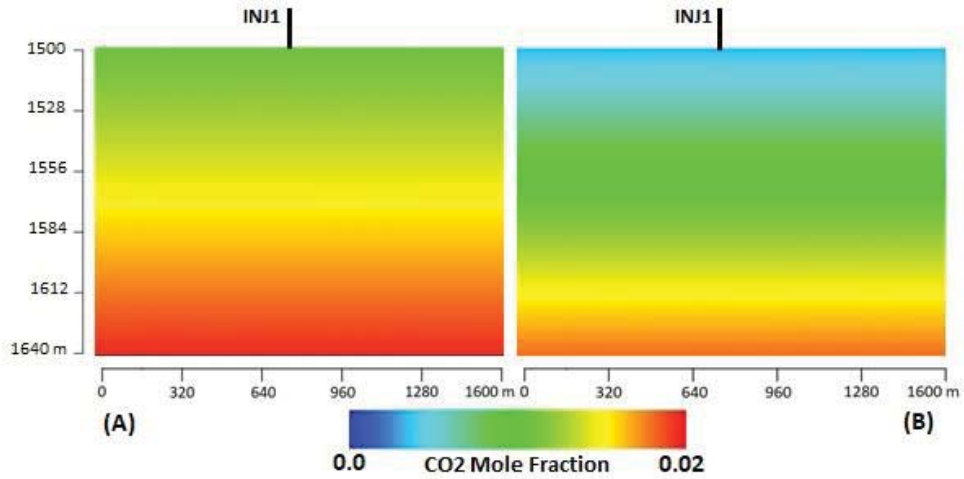

Fig. 6: Pressure build-up in the aquifer after 20 years. A) Without cooling system. B) With cooling system.

The impact of the amount of injected CO_2 (injection rate) into the aquifer on CO_2 solubility is demonstrated in Fig. 7 based on Kilogram-Mole (Kg-M). The figure shows that as the amount of injected CO_2 increases, the solubility of the CO_2 in brine also increases and moreover the impact of cooling is more significant when the amount of injected CO_2 is higher. This figure presents the comparison between the amount of dissolved CO_2 in the normal CO_2 injection under supercritical conditions and the injection of CO_2 with a lower temperature. As the amount of CO_2 injection increases, the amount of dissolved CO_2 in the brine also increases but with a higher rate. It means that as the injection rate increases the percentage of dissolved CO_2 also increases. As can be seen there is no significant change in solubility down to 0.2 Mt/year. It shows that this method can be

used in the projects with high availability of the CO_2 where the CO_2 injection rate is high enough (near 1 Mt/year and above).

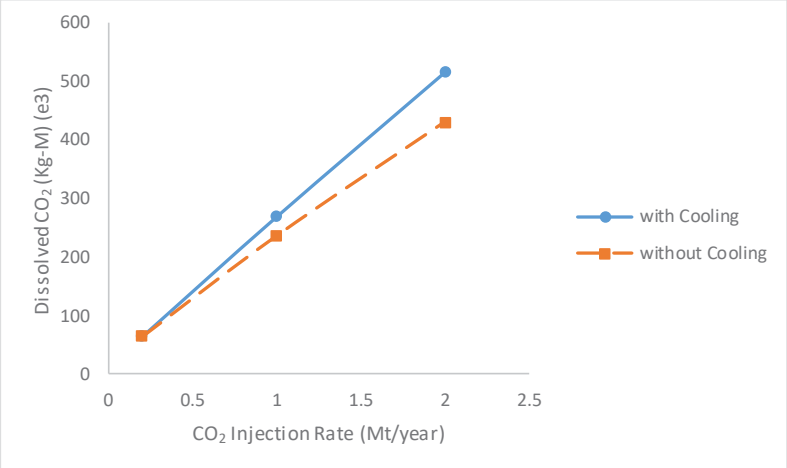

Fig. 7: impact of the amount of injected CO_2 and cooling on CO_2 solubility in brine after 120 years.

The amount of mobile CO_2 in the aquifer based on the CO_2 injection rate and the cooling effect is shown in Fig. 8. The results show that the cooling has an indirect impact on the amount of mobile (free) CO_2 in the medium in comparison to the CO_2 injection without cooling. The amount of free CO_2 in the aquifer increases due to the increase in the amount of total injected CO_2. The impact of cooling and the CO_2 injection rate on the amount of trapped CO_2 is shown in Fig. 9. The amount of residually trapped CO_2 increases with an increase in the total amount of injected CO_2; however, this increase is less for the system with cooling compared to the standard CO_2 injection method without cooling. When the cooling effect is applied more CO_2 is dissolved in the formation, and thus less CO_2 will remain residually trapped. Additionally, in this simulation, since cooling temperature create a two-phase regime for the injected CO_2 and a part of CO_2 is converted to liquid, the amount of residually trapped CO_2 is considered to be less.

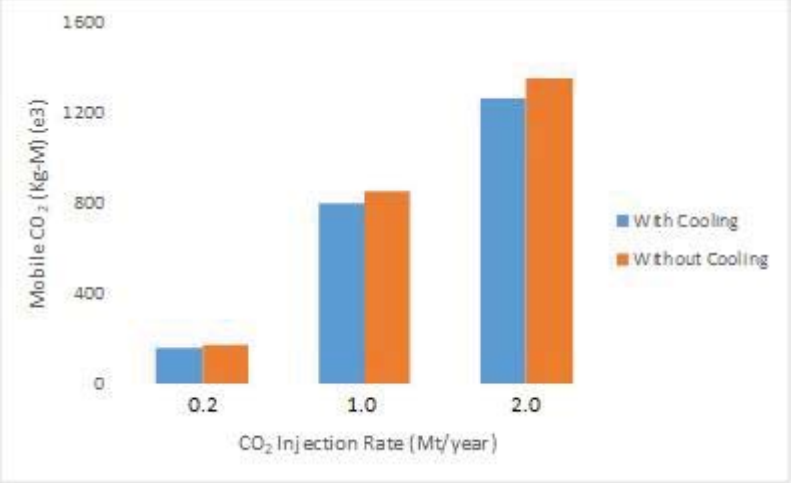

Fig. 8: Impact of CO_2 injection rate and cooling on mobile CO_2 in brine after 120 years.

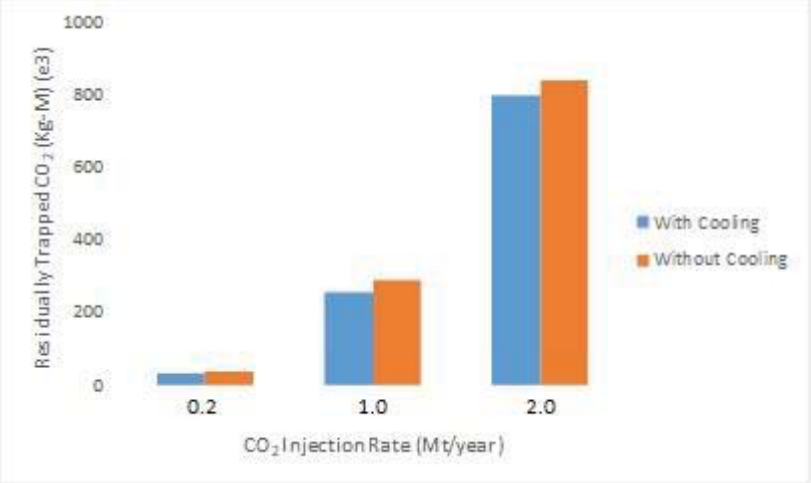

Fig. 9: Impact of CO_2 injection rate and cooling on residually trapped CO_2 in brine after 120 years.

4.2 Application of the downhole cooler tools at shallow (1000 m) and deep (2700 m) reservoirs

In another exercise, as the storage reservoirs are located in different depths, the impact of the depth of the reservoir was investigated with the new cooling technique. Two different reservoir depths were imposed in the model other than the base case: 2700 m (with a geothermal temperature of 98 ˚C) and 1000m (with a geothermal temperature of 35 ˚C). The results show that at a depth of 2700 m as the temperature decreases from 98 ˚C to 68 ˚C in the vicinity of the wellbore the solubility of CO_2 in brine does not change notably by this temperature decrease. This is because in this range

of pressure and temperature this change in temperature does not lead to a significant increase in the CO_2 solubility in brine. Although, the density and viscosity of CO_2 will increase up to 22% and 33%, respectively; CO_2 is still in the supercritical condition and will rise towards the caprock with the same pattern (Fig. 10). Although it should be noted that in some cases CO_2 will reach the formation with a temperature less than the geothermal gradient itself (Bissell, Vasco et al. 2011b); however, after a while an equilibrium temperature higher than CO_2 temperature will be achieved. In our study, this phenomena is not considered, however, the main idea is to show the impact of the temperature decrease in the wellbore on the CO_2 solubility in the aquifer.

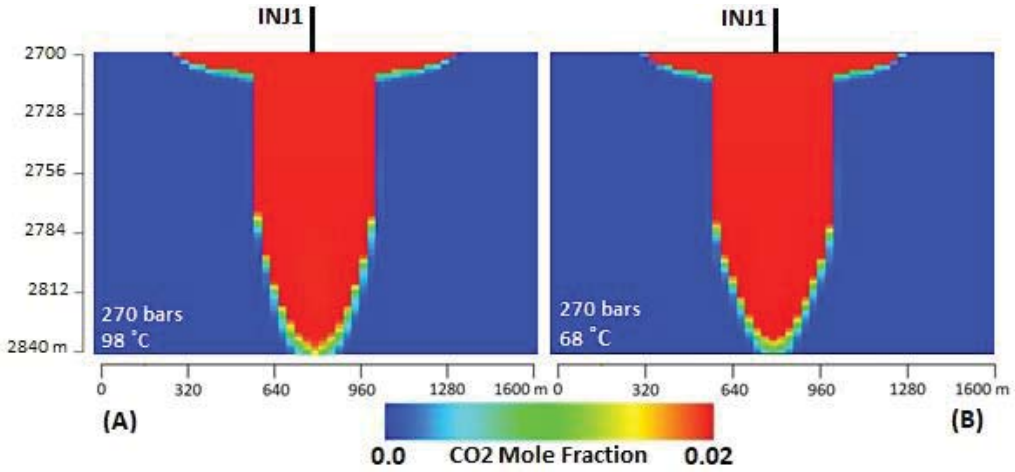

Fig. 10: The results of the variation of temperature (A): 270 bars, 98 ˚C (B): 270 bars, 68 ˚C.

On the other hand, a temperature decrease down to 25 ˚C was investigated in the model at a depth of 2700 m (Fig. 11). This huge temperature decrease creates a considerable increase in the amount of dissolved CO_2 in brine and the saturation distribution of CO_2 in the aquifer will change due to the phase change of CO_2. The simulation results show that the amount of dissolved CO_2 in brine increases up to 13 % at the end of the injection period in comparison to the case without cooling. Creating such a temperature decrease in this depth, however, seems controversial in practice.

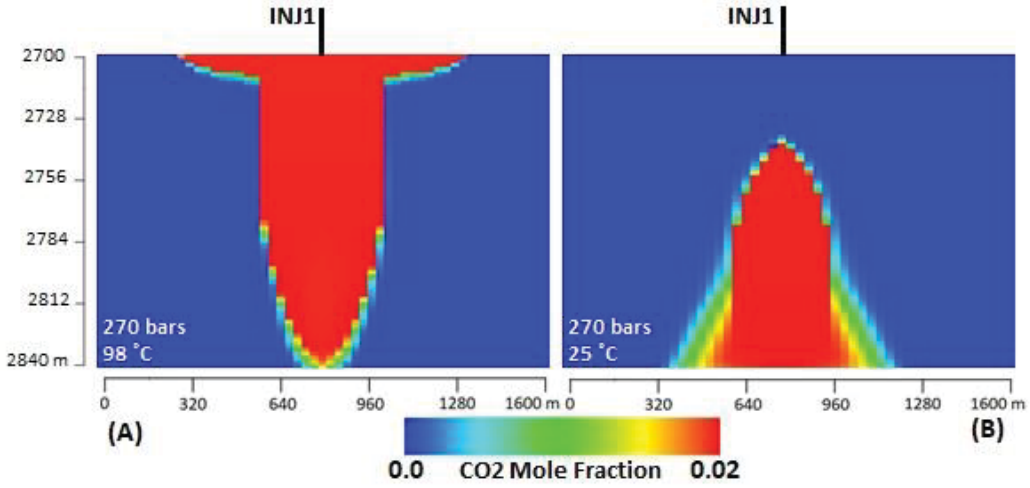

Fig. 11: The results of the variation of temperature (A): 270 bars, 98 ˚C (B): 270 bars, 25 ˚C.

At a depth of 1000 m, the temperature is reduced from 35 ˚C to 15 ˚C. The temperature could not be reduced less than 12 ˚C in this case because of the software limitations and moreover the temperature lies under the hydrate formation zone. The decrease in temperature and phase change will increase CO_2 solubility in brine and change the CO_2 plume distribution in the aquifer. Fig. 12 shows the CO_2 mole fraction and distribution for this case. The figure shows that through the temperature decrease the CO_2 will sink to the formation and does not rise upwards during the injection. Dissolution will increase up to 7 % at the end of injection period in comparison to the case without cooling.

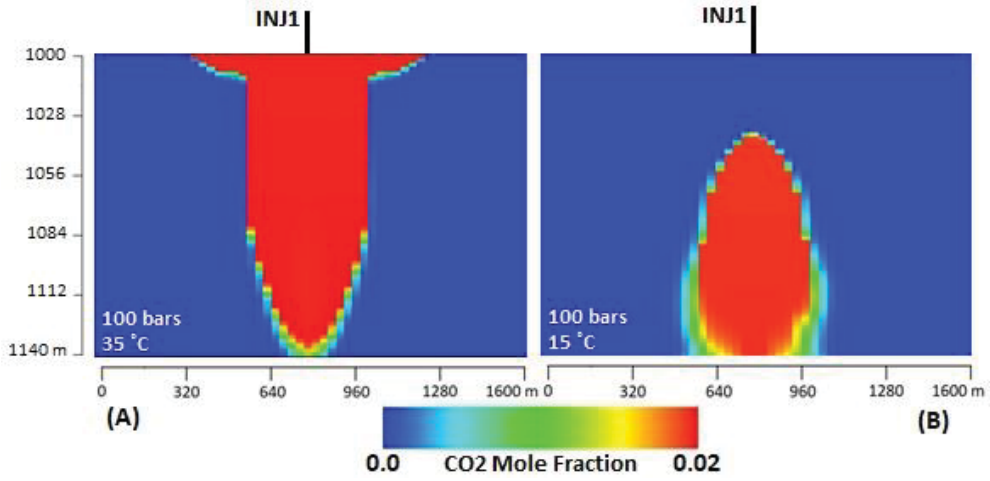

Fig. 12: The results of the variation of temperature (A): 100 bars, 35 ˚C (B): 100 bars, 15 ˚C.

Fig. 13 shows the increase in CO_2 dissolution in brine during and post injection for all the three depths. The results show that the CO_2 solubility will increase up to 7%, 6% and 13% at the end of injection period and up to 14.5%, 13% and 21% at the end of post injection period for the depths of 1000, 1500 and 2700m, respectively. Fig. 14 shows the average CO_2 saturation in the whole aquifer during and post injection for all cases. When CO_2 is injected in a model with low temperature the CO_2 saturation in the medium is lower because more CO_2 is dissolved in the formation brine. Additionally, even after the injection stops the average CO_2 saturation decreases with a higher slope which is an indication of a higher dissolution rate compared to other models. Table 2 shows the summary of the results of all the sensitivity analysis with depth.

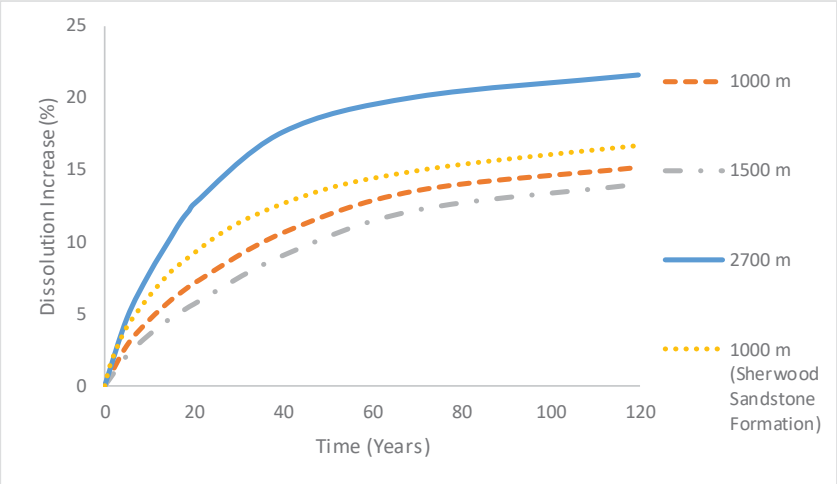

Fig. 13: Application of the downhole cooler tools in different depths and its impact on CO_2 solubility in the aquifer.

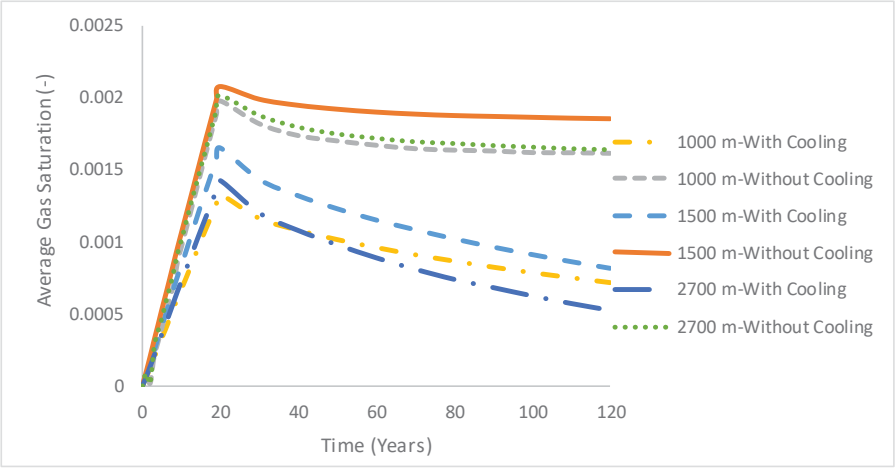

Fig. 14: Average CO_2 saturation in the whole aquifer for different depths.

Table 2: Increase in solubility of CO_2 in aquifer brine at the end of injection.

Depth (m)	Initial temperature (˚C)	Temperature at the sand face (˚C)	Increase in solubility at the end of injection (%)
1000	35	15	7
1500	52	20	6
2700	98	68	~0
2700	98	25	13

5. Application of downhole cooler tools in a real field

The British Geological Survey (BGS) has considered a field in Lincolnshire as a potential storage site near to future potential capture sites (i.e. Ferrybridge Power Station). The saline aquifer in this area locates in the Sherwood Sandstone Group with a Mercia Mudstone Group as the caprock (Smith, Campbell et al. 2011). The dimensions of the model are 43 km * 33 km * 600 m thick and it is discretised to 96 *67 *15 grid blocks. The mean permeability for the storage formation is 500 mD and 0.005 mD for the low permeable cap rock layer. The ratio of vertical to horizontal permeability is considered to be 0.1 due to the sedimentation in this region. The original model is large with a top surface area of 1419 km^2; thus, in this study a sector of the model was considered for the simulation (Fig. 15).

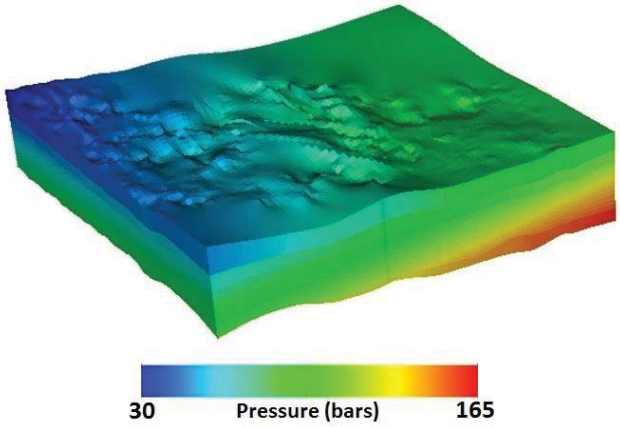

Fig. 15: The simulation model for the Lincolnshire field showing the pressure distribution.

The injection formation has an initial pressure of 100 bars and temperature of 35 ˚C. CO_2 is injected to the formation through a horizontal well with a temperature of 15 ˚C by adding the THERMAL option to the model. The injection rate is determined to be at a constant rate of 1 Mt/year. The pressure constraint is considered to be 90% of the fracture pressure of the caprock as explained earlier. In this model CO_2 is injected for 20 years and then the injection stops and the simulation runs for a further 100 years. Fig. 16 shows CO_2 mole fraction in brine at the end of the injection period. As can be seen CO_2 is more dissolved in the brine and has sink more downward to the aquifer as a result of colder (liquid) CO_2 injection with higher density.

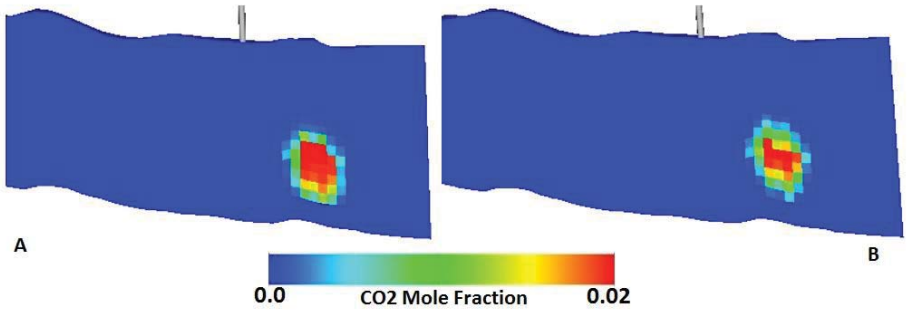

Fig. 16: CO_2 dissolution in brine after 30 years of injection. A) With cooling system. B) Without cooling system.

Fig. 17 shows the average CO_2 saturation in the formation. The plot determines that by the use of downhole cooling the average CO_2 saturation in the free phase has decreased and it becomes dissolved more in the formation brine. The percentage of dissolution increase is shown in Fig. 14 for

the real model and the solubility has increased up to 9.7% at the end of the injection and 16.1% 90 years after the injection has stopped.

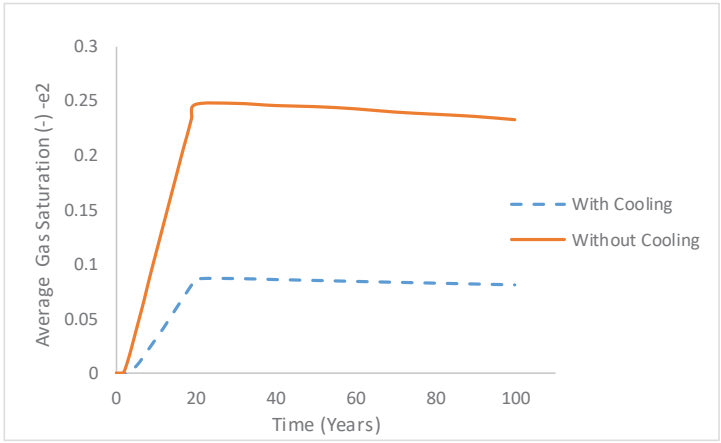

Fig. 17: Average CO_2 Saturation in the aquifer in the Sherwood sandstone model.

Conclusion

The results of this study show that through the use of downhole cooler equipment the amount of dissolved CO_2 in brine increases and consequently the storage security improves. If the temperature of the downhole, where the CO_2 contacts the formation brine, decreases to the lowest possible safe operational temperature, the solubility of CO_2 in brine increases to the highest possible value. Thus, more CO_2 becomes dissolved in the brine during the injection. When CO_2 is dissolved in brine the density of brine increases and the CO_2 plume will not move upwards as rapidly. It sinks into the formation and because of the higher density and viscosity the viscose forces will be more significant than the buoyant forces. Furthermore, in this method CO_2 is injected in the supercritical phase at the surface and in the length of injection tubing, although the temperature decrease and the phase may change only in the wellbore which eliminates the risk of phase change in the tubing and consequent problems. Additionally, the overall field pressure increase will be less than that of supercritical CO_2 injection due to the higher CO_2 dissolution in brine and also because of the lower volume of CO_2 when it is turned to liquid.

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